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A Dynamic Incentive Mechanism for Transmission Expansion in Electricity Networks: Theory, Modeling, and Application[†]

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and

Hannes Weigt*

Abstract
We propose a price-cap mechanism for electricity-transmission expansion based on redefining transmission output in terms of financial transmission rights. Our mechanism applies the incentive-regulation logic of rebalancing a two-part tariff. First, we test this mechanism in a three-node network. We show that the mechanism intertemporally promotes an investment pattern that relieves congestion, increases welfare, augments the Transco´s profits, and induces convergence of prices to marginal costs. We then apply the mechanism to a grid of northwestern Europe and show a gradual convergence toward a common-price benchmark, an increase in total capacity, and convergence toward the welfare optimum.

Keywords: Electricity transmission expansion, incentive regulation

JEL: L51, L91, L94, Q40

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I INTRODUCTION

Efficient transmission expansion is a major concern in electricity markets around the world. In the United States, network congestion is managed according to a variety of regulatory systems. Regions where restructuring has not occurred use transmission-loading relief, a procedure that physically manages constraints by rationing access to portions of the transmission network. Elsewhere, areas administered by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) generally employ market-based methods to manage congestion and promote network expansion.[1] Yet congestion costs have increased considerably, particularly in the Midwest (Dyer 2003) and in the markets in the PJM, Southern Connecticut, and New England. In 2006 the U.S. Department of Energy identified two areas of critical congestion, the Atlantic coastal area and Southern California, as well as four congestion areas of concern (U.S. DOE 2006).

In addition, transmission investment in the United States has declined in recent years (Joskow 2005). The U.S. regulator, the Federal Energy Regulatory Commission (FERC), proposed policies based on using merchant mechanisms, but little effort has been made to apply regulatory mechanisms based on performance. Implementation of regulatory measures is further complicated by the duality of attributions at the federal and state levels.[2]

In Europe, in contrast, the liberalization processes initiated in the late 1990s have led to national electricity networks with limited cross-border capacities that now form the backbone of the emerging internal market encompassing all of Europe. The grid, however, remains segmented into several regional and national subnetworks, resulting in little or no competition among countries. Diverging policy approaches have complicated the development of a functioning market, and a central focus for the European Union in recent years has been to harmonize congestion management (EC 2007). Europe's expected increase in renewable energy (primarily offshore and onshore wind) will require significant investment in transmission. Several studies have proposed ambitious schedules to extend the existing grid (e.g., DENA 2005), but an economical technical approach has not yet been designed that can cope with the need for expansion while accounting for effects on social welfare.

This article presents a new mechanism that seeks to achieve efficient long-term expansion of transmission networks by means of regulation and engineering. Our price-cap mechanism is

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[1] RTOs schedule and dispatch generators on regional networks, allocate scarce transmission capacity, monitor generators, coordinate network maintenance, plan new transmission links, and operate real time and diverse time-ahead markets for energy and ancillary services.

[2] In each state, Public Utility Commissions are responsible for reviewing applications for major new transmission facilities, granting permits, and regulating the bundled charges for transmission service made by vertically integrated firms to retail customers. FERC is responsible for regulating the prices for transmission service, but it generally lacks authority over transmission planning.

based on redefining the output of transmission in terms of point-to-point transactions or financial transmission rights (FTRs) and rebalancing the variable and fixed portions of two-part tariffs. We will show how this theoretical framework can be extended and applied in practice, independently of the technical nature of the network. This mechanism thus proves suitable for actual projects of transmission expansion in real-world grids. Our approach is novel in two ways. First, it combines the regulatory approach (an incentive mechanism) with the electrical-engineering approach; and second, we provide applications to show that the mechanism can work in reality.

The existing literature on transmission investment has taken either a merchant approach (long-term financial transmission rights or LTFTRs) or a regulatory approach (using the incentive-regulation hypothesis). The merchant approach is based on LTFTR auctions by ISOs. This approach is also known as a merchant mechanism because participation by economic agents in auctions is voluntary. Loop-flow externalities are addressed because the ISO retains some unallocated transmission rights (or *proxy* FTRs) during the LTFTR auction to protect FTR holders from the negative externalities of transmission-expansion projects (see Kristiansen and Rosellón 2006). This is equivalent to having the agents responsible for externalities “pay” them back (Bushnell and Stoft 1997) so that when FTR contracts exactly match dispatch, social welfare cannot be reduced through gaming.

The regulatory approach involves a commercial transmission company (Transco) that is regulated through price regulation to provide long-term investment incentives while avoiding congestion. Some mechanisms suggest comparing the Transco’s performance with a measure of loss of welfare. The Transco would then be penalized for increasing congestion costs in the network. Léautier (2000) analyzes a Bayesian approach under the congestion-management scheme in England and Wales. In this setup, the regulator offers the firm a menu of contracts that (according to the revelation principle) induces the firm to operate and build transmission lines efficiently while still allowing the firm to recover its costs. Joskow and Tirole (2002) propose a simple surplus-based mechanism to provide the Transco with enough incentives to expand the transmission network. The idea is to reward the Transco according to the redispatch costs avoided by the expansion so that the Transco faces the entire social cost of congestion.

A regulatory variation is the two-part tariff cap proposed by Vogelsang (2001), in which incentives for investment in expanding the grid derive from rebalancing the fixed and variable portions of the tariff. Vogelsang postulates transmission cost and demand functions with fairly general properties and then adapts regulatory adjustment processes to the transmission problem. For example, under well-behaved cost and demand functions, appropriate weights (such as Laspeyres weights) grant convergence to equilibrium conditions.[3] One criticism made of this approach, however, is that the properties of transmission cost and demand functions are little known but are suspected to differ from conventional functional forms. Hence Vogelsang's assumed cost and demand properties actually may not be valid in a real network context with loop-flows. Moreover, a conventional linear definition of transmission output is actually difficult to maintain because the physical flow through a meshed transmission network is complex and highly interdependent among transactions (see Bushnell and Stoft 1997, Hogan 2002a, 2002b).

An extension of Vogelsang's (2001) mechanism was recently proposed by Hogan, Rosellón, and Vogelsang (2007) (HRV). It combines the merchant and regulatory approaches in an environment of price-taking generators and loads. While Vogelsang's original mechanism (2001) is inherently relevant only to radial networks, the extended model is designed to account for expansions within meshed networks. The new mechanism is designed for Transcos but (like the Vogelsang 2001 model) could also be applied within an ISO setting. Transmission output is redefined in terms of incremental LTFTRs in order to apply the incentive mechanism to a meshed network.[4] The Transco maximizes profits intertemporally subject to a price-cap constraint on its two-part tariff, and the choice variables are the fixed and the variable fees. The fixed part of the tariff can be considered a complementary charge. The variable part of the tariff is the price of the FTR output, which is then based on nodal prices. Fixed costs are allocated so that the variable charges can reflect nodal prices. Thus variations in fixed charges over time partially counteract the variability of nodal prices, giving some price insurance to the market participants.

In the present article, we build on Vogelsang (2001) and HRV to propose a regulatory logic to incentivize a Transco to expand the network. As these authors, we focus on the Transco's monopoly price regulation and abstract from a possible substitution between transmission and generation expansion.[5] Our model is a mathematical program with equilibrium constraints (MPEC) , which will be presented in the second section of this article. It is decomposed into upper- and lower-level programs that are solved simultaneously. The upper-level problem is

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[3] See Rosellón (2007) for an application of the Vogelsang (2001) model to an electricity network with no loop flows.

[4] The detailed properties of cost functions when the transmission output is redefined in terms of point-to-point transactions (or FTR-obligations) are still an open field for research. However, both in this document and in other studies, we have found evidence that our approach is piece-wise differentiable and thus applicable to real networks. In a related recent paper, we explore the properties of FTR-based cost functions for distinct network topologies and find evidence that cost functions defined as FTR outputs are piecewise differentiable but that they contain sections with negative marginal costs. Our simulations, however, illustrate that such unusual properties do not stand in the way of applying price-cap incentive mechanisms to real-world transmission expansion (see Rosellón, Vogelsang, and Weigt, 2009).

the Transco´s profit maximization being subject to a price-cap regulatory constraint; the lower-level problem consists of an ISO that finds optimal loads and nodal prices through a power-flow model that maximizes welfare within a wholesale electricity market. Unlike HRV where the choice variables of the Transco´s constrained problem are the incremental FTR price (variable part) and the fixed part of its two-part tariff, while the choice variables in our new mechanism are line capacity and fixed fee.[6] This approach is equivalent, since the network capacity is a function of the FTR prices.

Under our new price-cap incentive scheme, the Transco's behavior is similar to that found in Vogelsang (2001) and HRV. Neglecting uncertainty in demand and generation, prices and quantities during each period are subject to a cap (adjusted by inflation and efficiency factors) as defined by the regulator. The cap is weighted with FTR outputs (typically Laspeyres). Generally speaking, network expansion occurs in ways that reduces congestion, thus implying a decrease in the Tranco's profit due to reduced congestion rents. Our mechanism permits the Transco to overcome the congestion-revenue decrease intertemporally by rebalancing its variable and fixed fees. Essentially, the idea is to make the investing firm the residual claimant to the surplus created through investments by allowing the reduction in economic rent achieved due to congestion to be compensated by an increment in the lump-sum component of the two-part tariff. This process then expands the grid to the point where the expected marginal revenues from congestion equal the marginal cost of adding new transmission capacity, the typical equilibrium condition for optimal expansion of transportation networks (see Crew, Fernando, and Kleindorfer 1995). [7]

The looped-flow nature of power in meshed networks prevents us from deriving an analytical solution for general settings (see HRV, pp. 17-19). We therefore apply numerical methods to our new mechanism. In the third section of this article, we apply the incentive mechanism to simple transmission structures based on a three-node network to determine the impact of loop flows on transmission investment decisions. Through the use of chained-Laspeyres weights, our regulatory mechanism intertemporally promotes an investment pattern that relieves congestion, increases consumer surplus, augments the Transco´s profits, and induces convergence of nodal prices towards marginal costs. The results also approach those of a pure

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[5] We also abstract from access-pricing problems for new generators that might be willing to interconnect to the Transco's network, as well as from potential strategic behavior from generators that might withhold capacity before or after the transmission capacity change or by colluding with the Transco.

[6] The equivalency between using either the capacity or the variable-price as choice variable is later discussed in footnote 11.

[7] In the non-Bayesian scheme of Loeb and Magat (1979), the company receives the whole consumer surplus as subsidy, and therefore maximizes the regulatory objective directly (provided there are no distributional weights), thus implying immediate convergence. In the dynamic incremental-surplus-subsidy scheme (ISS) of Sappington and Sibley (1988), the company receives a subsidy (or pays a tax) in each period equal to the difference between the increase in consumer surplus in the current period and profit of the previous period. This mechanism converges to welfare-optimal prices (assuming equal weights) in a single period.

welfare-maximizing model. They are robust to changes in line-extension costs and initial line capacities and reactances as well as to changes in demand elasticities. However, when generation costs at a certain node are increased (relative to other nodes), the transmission network will be expanded to allow imports of cheap generation from other nodes. This will then also imply larger profits for the Transco. In contrast, assumption of a capacity constraint on cheap generation implies a decrease in expansion of the grid and a consequent reduction in the Transco´s profits. Similarly, higher discount rates imply higher investment rates by the Transco because future earnings are weighted less in its profit stream.

In the fourth section, we apply our new incentive mechanism to a more realistic representation of an existing network with a diversified generation park to test whether the theoretical conclusions obtained are appropriate. We use a simplified grid with fifteen nodes and twenty-eight lines in northwest Europe that connects Germany, the Benelux countries, and France. Eight types of generation technologies are included, and it is assumed that initial congestion exists between Belgium and France and between Germany and the Netherlands. The results show that when starting from divergent prices, a gradual convergence occurs to a common price benchmark. At the same time, the total transmission capacity is significantly increased, the Transco´s profits are augmented, and a significant convergence occurs toward the welfare optimum.

Our contribution to the literature consists of improving the Vogelsang (2001) mechanism, both theoretically and numerically, to achieve the expansion of meshed loop-flowed transmission grids. We accomplish this upgrade by reformulating Vogelsang's original model into a two-stage problem that synchronizes the regulatory logic on expansion with the optimal power-flow determination by an ISO. This approach also implies a new way to analyze the economic nature of the cost and demand functions of transmitting electricity and to promote their efficient expansion.

Overall, our model proves to be workable from both theoretical and empirical standpoints. It provides considerable increases in social welfare, congestion relief, and profits for firms. The mechanism can be applied relatively easily and at low cost because the regulator needs only minimal information that is provided by market prices. We have observed that most of the larger electricity markets in the United States already have the three institutions necessary to implement our approach: an ISO managing the wholesale market, locational pricing, and FTR auctions.

II MODEL FORMULATION

Our model builds on the concept presented in HRV that redefines the output of a Transco in terms of financial transmission rights (FTRs). Accordingly, the applied mechanism has the following sequence of actions:

1. Given an existing grid with information on historic market prices, the regulator sets up the two-part pricing constraint.
2. Based on the market information available about demand, generation, network topology, and similar factors, the Transco identifies which lines to expand.
3. The Transco auctions off the available transmission capacity as point-to-point FTRs to market participants.
4. The ISO manages actual dispatch. According to locational marginal prices, the ISO collects the payoffs from loads and pays the generators. The difference between the two values represents the congestion rent of the system that is redistributed to the FTR holders.
5. The Transco can also set the fixed fee according to the regulatory price cap.

The mathematical model to capture this sequence is divided into upper- and lower-level problems that are solved simultaneously as an MPEC. The upper-level problem consists of the profit maximization of the Transco being subject to the regulatory constraint. The lower-level problem is the market-clearing of a wholesale electricity market that is network-constrained. The objective function of the (non-myopic) Transco is its profit over all periods and its choice variables are the line capacities k and the fixed fee F:

$$(1) \qquad \max_{k,F} \quad \pi = \sum_{t}^{T} \left[\sum_{ij} \tau_{ij}^{t}(k^{t}) q_{ij}^{t}(k^{t}) + F^{t} N^{t} - \sum_{i,j} c\left(k_{ij}^{t}\right) \right]$$

Transco profit function

The first term of this function represents the collected congestion rent defined as point-to-point FTRs q_{ij} between two nodes i and j multiplied by the FTR auction price τ_{ij}.[8] The second term represents the transmission revenue from fixed fee F collected by the Transco from the N consumers. The Transco is free to set the fixed fee as long as the regulatory price constraint is met (see equation 2 below).[9] The third term represents the costs the Transco bears when extending the capacity k_{ij} between two nodes according to the extension cost function $c(.)$. We

[8] Following Vogelsang (2001), who employs total transmission output, we use the total available FTRs in each period t, HRV use incremental FTRs following the practice in actual markets that hold FTR auctions (such as PJM). Hence, their output Δq_{ij} refers to the additional or *incremental* FTRs between i and j sold between periods t and $t-1$.

[9] An interesting extension would consider more general nonlinear tariffs with distinct private-preference parameters for each consumer. This undertaking would extend the model to an asymmetrical information environment.

consider a total time framework of T periods and assume perfect information; we neglect uncertainty about demand and generation.[10]

Note that FTR prices and the demand for FTRs are a function of the available capacity of the network. Thus the Transco's choice variables are the line capacities k_{ij} and the fixed fee F.[11]

In each period, the Transco is subject to a regulatory price cap:

(2) $$\frac{\sum_{ij} \tau_{ij}^{t}(k^{t}) q_{ij}^{w} + F^{t} N^{t}}{\sum_{ij} \tau_{ij}^{t-1} q_{ij}^{w} + F^{t-1} N^{t}} \leq 1 + RPI + X$$ regulatory cap

The prices and quantities of each period are linked with a weight mechanism w (such as Paasche or Laspeyres weights), and are subject to a cap defined by the regulator and considering inflation RPI and efficiency factors X. A grid expansion would generally be aimed at reducing the congestion rent of the system and would then decrease the Transco's profit from the FTR auction. Given the regulatory mechanism, the Transco can counter the decrease of auction revenues by increasing its fixed fee. By this mechanism, the Transco is incentivized to expand the grid even if the congestion rent decreases. As long as the rebalancing of the variable and the fixed fee compensates possible revenue losses from reduced congestion to a point where the per-unit marginal cost of new transportation capacity equals the expected congestion cost of not adding an additional unit of capacity, we can expect to observe expansion (see Crew, Fernando, and Kleindorfer 1995 and Vogelsang 2001).

If the demand and optimized cost functions can be differentiated and inflation and efficiency factors are ignored, the first-order optimality conditions of maximizing (1) subject to (2) look like:

(3) $$\nabla q_{ij}^{t} \tau_{ij}^{t}(k^{t}) - \nabla c^{*} = (q_{ij}^{w} - q_{ij}^{t}(k^{t})) \nabla \tau_{ij}^{t}$$ first-order conditions

Vogelsang (2001) and HRV analyse this key relationship to discover the incentive properties of the regulatory price-cap constraint. The later study pointed out the limited information that

[10] If a positive interest rate $r > 0$ were to be considered, each monetary part of the profit function would be multiplied by $(1+r)^{-t}$. In this article, we follow the standard approach in the literature on regulatory economics and concentrate on profit maximization under stable cost and demand conditions. Results are ambiguous when nonstable demand and cost functions are considered. Under such conditions, a profit-maximizing Transco subject to a chained Laspeyres constraint might establish prices that diverge from the Ramsey structure (see Neu 1993, Fraser 1995, Law 1995, and Brennan 1989).

[11] HRV assume that the network capacity and the FTR demand are functions of the FTR price τ, and thus their choice variables are the two parts of the Transco's tariff. In such a model, the minimum cost for each possible FTR price (and consequently for each possible FTR quantity) is obtained in a lower-level power-flow problem, and as a consequence, the optimal grid size k is derived. This minimum cost function is later plugged into an upper-level problem where the Transco maximizes its profits subject to a regulatory constraint similar to the constraint in Vogelsang (2001). Our approach of using as choice variables capacity k and the fixed fee F is thus generally equivalent (both for fixed or increasing demand) to the HRV approach.

can be derived. Due to the looped-flow nature of power flows in meshed networks, FTR-based demand and cost functions can only be differentiated piecewise and generally cannot be separated. Yet the local properties may in many circumstances be those of well-behaved functions. To test these insights, we will next apply numerical methods.

One problem in deriving an MPEC mathematical formulation for the mechanism is uncertainty as to the outcome of the FTR auction. We here redefine FTR auction income as the congestion rent collected by the ISO given the market-clearing prices. Because the considered set of FTRs is simultaneously feasible and the system constraints are convex, the FTRs satisfy the condition of revenue adequacy.[12] That is, equilibrium payments collected by the ISO through economic dispatch will be greater than or equal to payments required under the FTR obligations. Given the assumption of perfect information, this approach allows us to abstract from the explicit modeling of an auction mechanism. Therefore, the distribution of FTRs to specific market participants is not an output of the model. The profit objective function of the Transco is then rewritten as:

(4) $$\max_{k,F} \quad \pi = \sum_{t}^{T} \left[\sum_{i} (p_i^t d_i^t - p_i^t g_i^t) + F^t N^t - \sum_{i,j} c\left(k_{ij}^t\right) \right]$$ adjusted profit function

The first part of the Transco's profit rewrites the outcomes of the lower-level problem, that is, payoffs from loads d and payments to generators g. The prices p_i are the resulting market-clearing prices at each node i. FTR prices and locational prices are related via $\tau_{ij} = p_j - p_i$. In choosing the line capacities k_{ij} the Transco will determine resulting market prices and quantities and thus the collected congestion rent. The price cap is rewritten accordingly by replacing the FTR auction revenue with the collected congestion rent:

(5) $$\frac{\sum_{i} (p_i^t d_i^w - p_i^t g_i^w) + F^t N^t}{\sum_{i} (p_i^{t-1} d_i^w - p_i^{t-1} g_i^w) + F^{t-1} N^t} \leq 1 + RPI + X$$ Adjusted regulatory cap

The lower-level problem defines the wholesale-market outcome by taking into account power flows, line restrictions, and generation capacity limits:[13]

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[12] This has been shown for lossless networks by Hogan (1992), analyzed for quadratic losses by Bushnell and Stoft (1996), and generalized to smooth nonlinear constraints by Hogan (2000, 2002a, 2002b).

[13] Our model could be generalized to include security-constrained dispatch to take care of reliability issues and regulate the potential reduction in network reliability (and service quality) typical of price-cap mechanisms. Within a security-constrained dispatch and under normal contingencies, the Transco will not optimize the reliability level on its own initiative. Normal security-constrained, economic dispatch as actually employed in electricity applies the "n-1" limits under which the actual dispatch would remain feasible in the event of any of the monitored contingencies. Hence, there exists no dichotomy between the normal dispatch and the contingency-constrained dispatch. The normal "congestion" cost includes the economic cost associated with the contingency. Under these assumptions, all the economic costs are congestion costs covered by the FTRs. Only on "rare" contingencies (such as "one-day-in-ten-years" contingencies considered by Blumsack, et al., 2007) should the regulator/ or system operator should have an additional major regulatory role pursuing reliability. In such a context, reliability constraints could be introduced more formally. In practice, regulators, such as the FERC in Order 679, distinguish between congestion relief and reliability as two separate objectives. The formal modeling of a firm optimizing reliability endogenously is beyond the scope of our article.

(6) $$\max_{d,g} \quad W = \sum_{i,t}\left(\int_0^{d^*} p_i(d_i^t)\mathrm{d}d_i^t\right) - \sum_{i,t} mc_i g_i^t$$ ISO objective function

s.t.

(7) $$g_i^t \leq g_i^{t,\max} \quad \forall i,t$$ generation constraint at node i

(8) $$\left|pf_{ij}^t\right| \leq k_{ij}^t \quad \forall ij$$ line flow constraint between i and j

(9) $$g_i^t + q_i^t = d_i^t \quad \forall i,t$$ energy balance constraint at node i

We assume that the wholesale market is managed by an ISO that is maximizing social welfare W in a perfectly competitive environment. [14] Demand d and generation g are located at specific nodes i within a meshed network. Welfare is derived by obtaining the gross consumer surplus and subtracting the total generation costs.[15] We assume a linear demand behavior $p(.)$ and constant marginal generation costs mc_i.

The maximization of welfare is subject to technical constraints. First, actual generation g_i cannot exceed the available generation capacities g_i^{max} (equation 7). Second, the power flow pf_{ij} on a line connecting i and j cannot exceed the available transmission capacity k_{ij} defined by the Transco (equation 8). Third, the energy-balance constraint ensures that demand at each node is satisfied by either local generation or net injections q_i (equation 9).

The choice variable of the Transco is the actual line capacity k_{ij}, which impacts the allowed power flow on that line (equation 8) and simultaneously affects the whole flow pattern in the meshed network. The linkage of line capacity and power-flow distribution is derived using a DC load-flow approximation (see Appendix A). The derivation of the Karush–Kuhn–Tucker conditions of the lower level problem is reformulated as a mixed complementarity problem. These first-order conditions are in turn included as constraints in the Transco's maximization in addition to the price-cap constraint (equation 5). The problem is incorporated as MPEC into GAMS.[16] The Transco's choice of available capacity k_{ij} therefore directly impacts the resulting market prices and thus its variable-income component. The locational prices p_i are derived as duals of the energy-balance constraint.

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[14] The lower-level problem is an approximation of the ISO dispatch problem. We assume that the regulator is independent from the ISO, and that the regulator establishes the regulatory price-cap constraint based on the ISO information. Inclusion of the lower-level welfare-maximizing ISO power-flow problem implies that (regulated) prices are always set optimally, given the capacities determined by the investment process in the upper level. In the original Vogelsang (2001) formulation, the Transco would set profit-maximizing prices according to a price- cap determined by the regulator according to prices and quantities in the previous period. But in such a model, it is possible that prices do not necessarily coincide with a welfare - maximizing criterion.

[15] This approach allows a more straightforward mathematical expression of the three components of welfare in electricity markets: consumer rent, generators' rent, and congestion rent.

III THREE-NODE CASE

We now test the properties of our incentive mechanism by applying it to a three-node example, which allows us to analyze the impact of loop-flowed lines on the Transco's investment decision.[17] We next describe the basic model and present the results. Because our analysis is based on several simplifying assumptions, we also conduct a robustness test by gradually relaxing the constraints. Similarly, the welfare properties of our regulatory approach are evaluated.

III.i Basic model outcome

We assume a three-node-network topology that is given and fixed (Figure 1).[18] We further assume that sufficient generation exists at nodes 1 and 2 and that no generation capacity exists at node 3. For simplicity, the marginal costs of generation are fixed at zero. Each node has a linear demand function $p(d_i)$. The locational price at nodes 1 and 2 will be at marginal cost level and the price at node 3 will include possible congestion charges because no local generation capacities are available.

The initial line characteristics represent a congested system. The available transmission capacity is such that node 3 faces a higher price than nodes 1 and 2. The system is assumed to be symmetrical with respect to capacities and line reactances. According to its objective function (equation 4), the Transco is free to choose the line capacities $k_{ij.}$. We specify extension costs via a linear cost function $c(.)$ using a constant extension cost factor *ecf*:

(10) $$c_{ij}^{t} = ecf \cdot \left(k_{ij}^{t} - k_{ij}^{t-1}\right)$$ extension cost function

We assume that the Transco extends the capacity; thus $k_{ij}^{t} \geq k_{ij}^{t-1}$.[19]

Table I summarizes the initial network characteristics. As noted, we later relax these assumptions to analyze the impact on the Transco's extension behavior.

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[16] The General Algebraic Modeling System (GAMS) is designed for solving linear, nonlinear, and mixed integer - optimization problems (Brooke et al., 2008). The MPEC formulation is solved using the NLEPC solver.

[17] Three-node networks serve as the spanning structure for more generally meshed grids. Blumsack has analyzed large networks under the Wheatstone bridge (roughly defined as the first link whose addition causes a loop flow in an electricity network). See Blumsack (2006, sec. 5, also Ekelöf 2001).

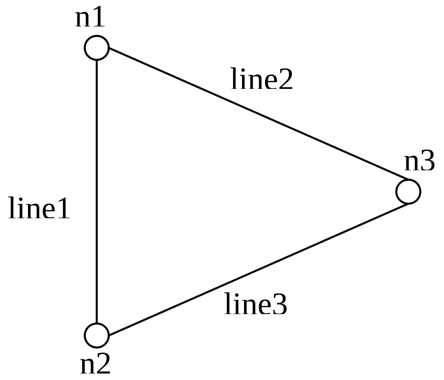
[18] Properties of FTR-based transmission cost functions under changes in ptdfs and topology remain an open question in the literature (see HRV, section 4).

[19] The possibility of reducing capacity in the given MPEC formulation presents two problems. First, reduction of capacity would also be costly; thus at 0 the function would have a kink. Second, following equation 12, the line's reactance increases with each reduction converging to infinity if the line is completely taken out (capacity kB_{ijB} set to 0). This may result in infeasible solutions due to numerical limitations of the modeling software. The HRV general formulation however allows at the optimum the choice of transmission capacity reductions that are welfare improving. Hogan (2002a), and Kristiansen and Rosellon (2006) define expansion protocols that apply to both increases and decreases in grid capacity. Transmission investment is based on the ISO (or the Transco) retaining some FTRs (and capacity) in order to deal with possible negative externalities caused by expansions (or reductions) in the network that harm other FTR holders. FTR auctions --and the respective capacity expansions (or reductions) -- can then be designed in such a way so that welfare does not decrease, even for those (negatively) affected (but hedged) investors. Finally, is it possible for a transmission company to add capacity in a congested network in a way that would not change locational prices or improve deliverability to customers. Expanding a line "downstream" of a significant constraint might be such an example (see also Bushnell and Stoft, 1997).

Table I: Initial Network Characteristics

	n1	n2	n3
Demand	$p(d_i) = 10 - d_i$		
Generation costs	$mc_i = 0$		n.a.
	line1	line2	line3
Extension cost	*ecf = 1*		
Initial capacity	2 MW		
Initial reactance	1		

Figure 1: Three-node Network



We consider a time framework of ten periods. The Transco is maximizing its expected returns over all periods. Regarding the price cap, we assume a classic chained Laspeyres approach, weighing the current period's prices with the previous period's quantities. We ignore inflation or efficiency targets:

$$\frac{\sum_i (p_i^t d_i^{t-1} - p_i^t g_i^{t-1}) + F^t}{\sum_i (p_i^{t-1} d_i^{t-1} - p_i^{t-1} g_i^{t-1}) + F^{t-1}} \leq 1 \qquad (11) \quad \text{Laspeyres cap}$$

The number of consumers N is considered to be constant over all periods and normalized to 1, and the initial fixed fee is equal to 0.

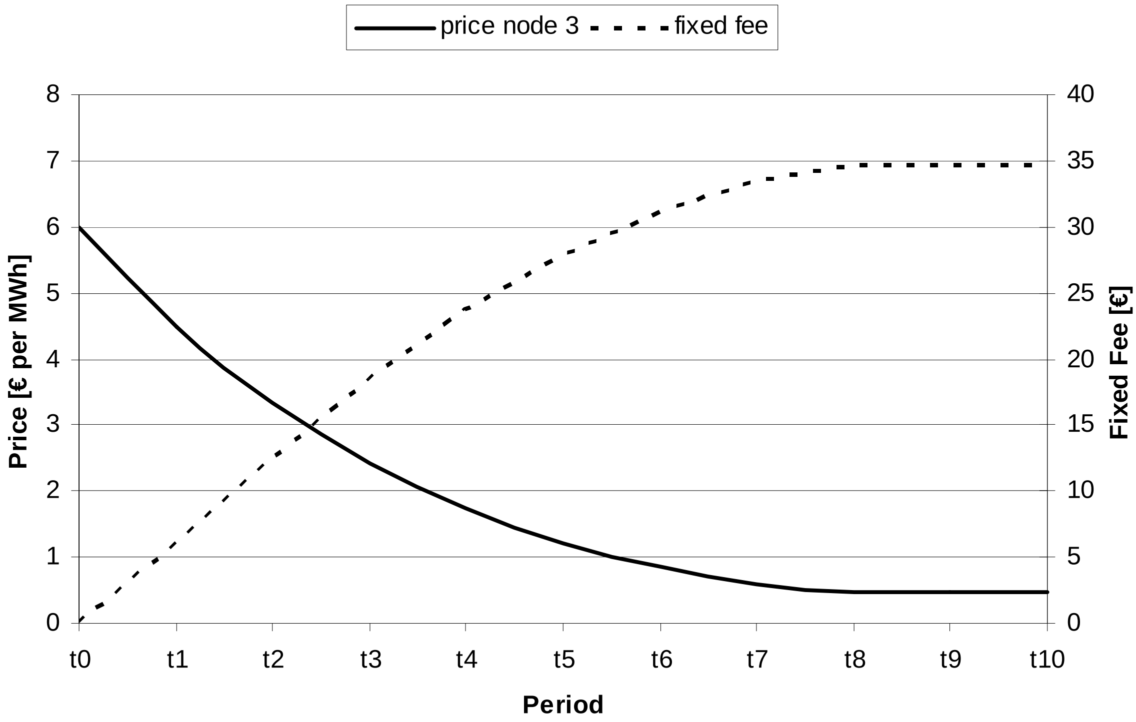
Given these conditions, the approach shows an investment pattern that reduces the price at node 3 over time close to the marginal costs of generation (Figure 2). The final price pattern obtained represents the point where the per-unit marginal cost of new transportation capacity equals the expected congestion cost of not adding an additional unit of capacity. Given the initial grid conditions, providing an additional MW energy at node 3 decreases the nodal congestion price difference by 1 € due to the assumed linear demand function with a slope of -1. Thus after the capacity expansion, an increased demand will be satisfied (one MW more) but at a reduced price (one 1 € less). From this new income, the Transco still subtracts the extension costs (of 1 € per MW line capacity). The new profit, however, is positively counterbalanced further by the Transco via the fixed fee *F*. This combined behavior is precisely the one that promotes successive grid extensions over time based on the rebalancing of the merchant and the regulatory mechanisms represented, respectively, by the FTR revenue and the fixed-fee revenues.

Compared to the initial congested grid conditions, consumer rent increases by about 35% in period 10 due to the reduced prices and increased demand. Likewise, the Transco's profit increases due to the balancing of congestion revenues and the fixed fee. If the Transco does not expand the grid, its profits would be 30 % lower (see Appendix B).

Due to the symmetry of the network characteristics, the extension pattern is not a fully unique solution. The loop-flowed line 1 is never subject to expansions,[20] and the Transco increases the capacities of lines 2 and 3 each period by decreasing amounts. Although the total amount of expanded capacity in each period is unique, its distribution to either line 2 or 3 is not unique and can vary with each model run. This outcome occurs because we assume similar cost factors and initial line parameters for both lines and have symmetric generation structures at nodes 1 and 2.

[20] Rebalancing the net injections at nodes 1 and 2 produces counter-flows that keep the power flow on line 1 stable, and thus there is no need to expand.

Figure 2: Price and Fixed-fee Development for the Base Case



III.ii Tests for Robustness

Testing for robustness will depend on the assumptions made.[21]

Initial line capacities: Our base case assumed a congested system with 2 MW of capacity on each line. If we decrease or increase the initial capacity by the same amount on each line, the general results do not change (although absolute levels differ). If we relax the symmetry assumption and increase the initial capacity of either line 2 or 3 compared with the other lines, then the absolute values are lower as the initial congestion is reduced. The largest expansion occurs on the line with the lower initial capacity.

*Initial line reactance: R*eactances define how the power flow "splits" on each line. Increasing the reactance of one line compared with the remainder of the grid reduces the share of power flow on that line and increases the flow on the others. Changing single line reactances in our model, however, does not alter the basic results when compared with the base case with respect to prices.

Line extension costs: Our base case assumed that all lines have similar expansion cost factors (*ecf).* Increasing the *ecf* for either line 2 or 3 does not alter the price pattern when compared with the base case because the entire grid expansion is focused on the cheaper line. Increasing the reactance of the more expensive line (e.g., to resemble an increased length) has no impact on the outcome.

[21] An overview about the obtained numerical results is presented in Table II and Appendix B.

These results suggest that altering the network assumptions under the given simplified-grid topology has no major impact. We observe a gradual grid expansion that reduces congestion within the system and thus the price at node 3 as well as an increase in consumer rents and the Transco's profit.

In addition to modifying the initial value of line parameters, changes in the assumptions about generation, demand, and the length of the observation period may impact the model outcome:

Generation costs: Given that most electricity markets face a variety of generation technologies, the Transco must consider price structure because it greatly affects the resulting power flows. Increasing generation costs at node 2 in our model leads to a new price pattern (node 2 now faces a price larger than zero). A large fraction of local generation at node 2 will be replaced by injections from the grid, which in turn increases the Transco's profits due to a higher transport volume. The results confirm these assumptions in that we observe a significantly larger amount of capacity extension and higher profits for the Transco. Prices at nodes 2 and 3 gradually decrease, whereas prices at node 3 behave identically to the base case.

Generation capacities: If cheaper generation has already reached its maximum capacity limit, additional transmission capacity may not increase the transmission volume. We model this scenario by reducing the capacity of the cheap generation at node by one to fifteen MW while keeping the more expensive generation at node 2 unrestricted. Although we find the same initial market outcome as in the upper-level case, the Transco should not increase the network capacity significantly because only a limited amount of additional transmission will occur, thus producing a lower profit. The results confirm our assumptions: the prices at nodes 2 and 3 drop but remain higher than in the cases without restrictions, and the profit is lowered as the transported energy decreases.

Demand behavior: The initial demand function represents a relatively elastic consumer behavior. In the short term, the demand for electricity is inelastic, and congestion therefore can lead to significantly higher prices without altering the transported energy by large amounts. Consequently, we changed the demand function to $p_i(d_i) = 1000 - 10d_i$ and kept the remaining parameters the same as in the base case. The results show that although the absolute values are significantly higher, consumers still have an equivalent decrease in price. Thus the increased congestion rent due to the more inelastic demand does not change the incentives for the Transco to relieve congestion.

Number of periods: The limited time frame of the model as well as the missing discounting of future payments can bias the outcome. If we extend the time frame to 100 periods, we observe a much slower price decrease than in the case of ten periods. This result, however, is caused by the missing discounting as current and future payments are weighted equally by the Transco. Introducing discounting into the model reduces the impact of the number of periods considered. The higher the discounting, the more rapid the investment becomes because future earnings are weighted less by the Transco.

III.iii Welfare Properties

To determine whether the results produced by our model also imply desirable increases in welfare , we compare it with a model in which a benevolent welfare-maximizing ISO administers the line capacities as choice variables.[22] In this model, the Transco is omitted from the formulation, and the basic market-clearing equations are extended. Thus network extensions become part of the welfare-objective function:

$$(12) \qquad \max_{d,g} \quad W = \sum_{i,t}\left(\int_{0}^{d^*} p_i(d_i^t)\mathrm{d}d_i^t\right) - \sum_{i,t} mc_i g_i^t - \sum_{i,j} c\left(k_{ij}^t\right) \text{ ISO objective function}$$

s.t. equations (7) to (13)

There is a large number of robustness tests and we present only two in detail: asymmetric limited capacity and unlimited generation capacity. The remaining results show a similar general behavior, although with different absolute values.[23] Table II summarizes the outcomes of comparing the base case of no grid extension, the case of capacity extension under our regulatory approach, and the case of a benevolent ISO. The case of non-extension represents the initial network conditions, and thus congestion and prices are the highest. In the case of our regulatory mechanism, we observe an increase in consumer surplus and in the Transco's profit as well as a decrease in congestion rents and nodal prices. The results of the regulatory approach are relatively close to a pure welfare-maximizing outcome and suggest a convergence over time toward the welfare optimum within a relative short time frame (see Appendix D).

Furthermore, the case with limited generation capacities demonstrates a common outcome in the case of congested markets: if congestion is relieved, prices converge to a common level, and thus areas with initially low prices may afterward face higher prices due to increased export. This may cause particular concern when implementing the approach in existing markets.

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[22] This model is built only as a benchmark to evaluate numerically the welfare-convergence properties of our own mechanism. Our model seeks to decentralize investment decisions, so that market players are incentivized to invest. In reality, the ISO might not be able to obtain the necessary information to carry out expansion based on market criteria as modeled in the welfare benchmark.

[23] A list of results can be found in Appendix B.

We therefore conclude that given the simplified topology of a three-node network, our approach has robust welfare-enhancing properties. Although the absolute values of prices, rents, and capacities are changed by varying the assumptions, the Transco is incentivized to expand the grid in such a way that market prices converge toward the welfare optimum.

Table II: Comparison of Regulatory Approach with Welfare Maximization (values refer to the last period, t10)

	Asymmetric generation costs, limited generation capacities			Asymmetric generation costs, unlimited generation capacities		
	No grid extension	Regulatory Approach	Welfare maximization	No grid extension	Regulatory approach	Welfare maximization
Consumer rent	98.50 €	142.93 €	148.01 €	98.50 €	118.85 €	120.61 €
Producer rent	0.00 €	0.00 €	0.00 €	4.35 €	13.46 €	15.00 €
Congestion rent	22.00 €	6.93 €	1.98 €	22.00 €	4.10 €	1.98 €
Total welfare	120.5 €	149.9 €	150.0 €	124.9 €	136.4 €	137.6 €
Extension sum	-	4.59 €	4.90 €	-	15.28 €	15.80 €
Capacity: line 1	2.00 MW	2.00 MW	2.00 MW	2.00 MW	9.75 MW	9.90 MW
Capacity: line 2	2.00 MW	5.90 MW	6.00 MW	2.00 MW	9.53 MW	9.90 MW
Capacity: line 3	2.00 MW	2.70 MW	2.90 MW	2.00 MW	2.00 MW	2.00 MW
Price: node 1	0.00 €	0.90 €	1.00 €	0.00 €	0.00 €	0.00 €
Price: node 2	1.00 €	1.00 €	1.00 €	1.00 €	0.25 €	0.10 €
Price: node 3	6.00 €	1.41 €	1.10 €	6.00 €	0.47 €	0.10 €

IV APPLICATION TO A REAL-WORLD NETWORK

IV.i Model and Data

We test the insights obtained in the previous sections by applying our approach to a more realistic representation of an existing electricity network with a diversified generation park. Figure 3 illustrates a simplified grid of northwestern Europe connecting Germany (D), the Benelux countries, and France (F) based on Neuhoff et al. (2005). The model consists of fifteen nodes and twenty-eight lines. The nodes connecting France and Germany with their neighbors are auxiliary nodes without associated demand or generation. The lines connecting the German and French nodes with these auxiliary nodes are assumed to have unlimited capacities. Thus intra-country congestion in those two countries is not considered in detail. Each country node possesses given generation capacities (VGE 2006) and a reference demand (UCTE 2007). For additional simplification, we classify generation capacities into eight types and assume equal marginal cost levels for each type in all countries. With the exception of hydro power, renewable generation is not considered within this model. Table III provides an overview of the types, installed capacities, and marginal generation costs. A linear-demand behavior at the nodes is derived from the average load level for the node, a reference price of 30 €/MWh, and an assumed price elasticity of -0.25 at that reference point. We do not assume a demand growth rate. However, due to the linear demand function, increased network capacity and lower electricity prices results in a higher demand level.

The model formulation used for application to the European network is similar to the previous three-node approach. We consider a time frame of twenty periods and include a discounting factor with an interest rate of 8%.[24] We do not account for inflation or an efficiency factor within the Transco's price cap. The derived market results for one time period represent one hour; thus the Transco's revenue is multiplied by 8,760 for each period to approximate yearly incomes. Due to the average nature of both the load level and the generation structure, this approach omits the variable nature of real-world electricity systems. Line-expansion costs are assumed to behave linearly. Following Brakelmann (2004) and DENA (2005], we chose a value of 100 € per km per MW.[25] The Transco can only expand lines that already exist.

The starting conditions in the market are classified by a high price level in the Netherlands (Krim, Maas, Zwol), a divided price structure in Belgium (Gram, Merc), modest prices in Germany, and low prices in France. Congestion thus occurs between Belgium and France as well as between Germany and the Netherlands.

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[24] Twenty years are assumed to represent the discounting time of assets in electricity markets, and 8% trepresents an investment with rather low risk.

[25] This value is derived from upgrade costs for additional lines of the same voltage level as well as upgrades from 220 to 380 kV. The lumpy character of network investments is omitted.

Figure 3: Simplified Grid of Northwestern Europe (based on Neuhoff et al. 2005)

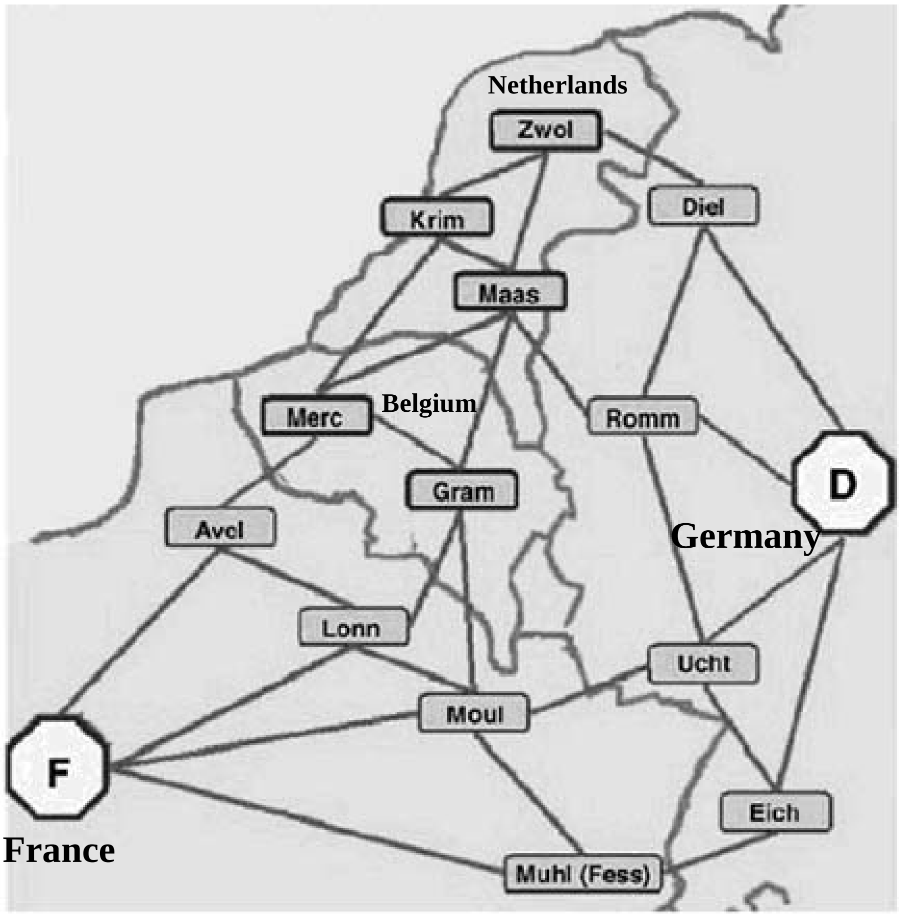

Table III: Plant Characteristics[26]

Plant type	Installed capacity	Marginal generation cost	Plant type	Installed capacity	Marginal generation cost
Nuclear	83 500 GW	10 €/MWh	Steam	28 000 GW	45 €/MWh
Lignite	21 000 GW	15 €/MWh	Gas turbine	5 500 GW	60 €/MWh
Coal	51 250 GW	18 €/MWh	Hydro	17 000 GW	0 €/MWh
CCGT	18 500 GW	35 €/MWh	Pumped storage	13 000 GW	28 €/MWh

IV.ii Results

To classify the results obtained, we again compare them with a case without grid extension (the starting conditions) and a benevolent ISO. Figure 4 shows the price developments at the country nodes over the periods considered. With an initially high price divergence in the market, we observe a gradual convergence to a common price level resembling the marginal cost of the last unit running. But the price convergence already occurs within the first ten periods. In the second half of the considered, the prices change only marginally, and additional expansions are relatively small. Consequently also, the convergence of the regulatory approach towards the welfare optimum takes place within the first ten periods, with most of the benefits achieved within the first five (see Appendix D). After the considered time

[26] A detailed locational overview of the demand and generation data is provided in Appendix C.

frame, we observe a close convergence of the regulatory approach toward the welfare optimum (Table IV). But even though overall welfare increases, consumer surplus decreases due to the increased prices that French consumers must pay. In the initial grid case, congestion separates the French market from the remainder of the grid. Thus the prices are at the marginal costs of local nuclear units, resulting in the lowest price in the market. If the grid is expanded, more of the available French nuclear power is utilized to satisfy demand at other nodes, and the price in France increases, thus reducing consumer surplus. This reduction cannot be offset by the lower prices in the Benelux countries because the demand in France is higher than the total demand in the Benelux. Yet the decrease in consumer rent is compensated by a significant increase in producer rent. The largest fraction of the additional company profit will benefit France because nuclear generation is now priced above their marginal costs.

The grid expansion totals about 300 million euros within the twenty periods (Table IV), a relatively small amount given the market's total welfare of 10 billion euros per year. This result arises mainly from assuming that the grid upgrades that occur will be less expensive than entirely new connections. But the total amount of new installed increases significantly, doubling the grid capacity initially available.

The Transco's profit over all twenty periods is about 25% higher under the regulatory approach than if the company had not extended the grid at all and just collected the initial congestion rent during all periods. Consequently the fixed fee increases as the congestion rent (represented by the price differences) decreases (see Figure 4).

Figure 4: Price Development in the European Model

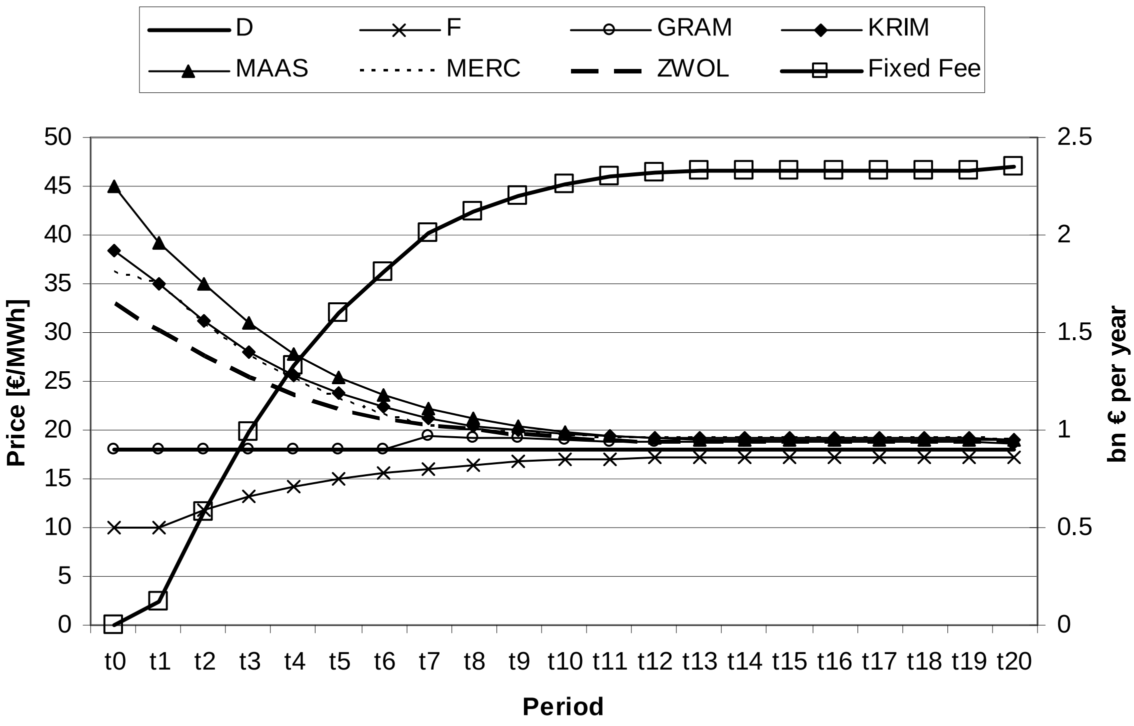

Table IV: Comparison of Regulatory Approach with Welfare Maximization (values refer to the last period, t20)

	No grid extension	Regulatory Approach	Welfare Maximization
Consumer rent [Mio€/h]	10.37	10.31	10.30
Producer rent [Mio€/h]	0.65	0.99	1.02
Congestion rent [T€/h]	107.8	20.20	7.13
Total welfare [Mio€/h]	11.13	11.32	11.33
Total extension sum [Mio€]	-	285.27	305.26
Total grid capacity [GW][27]	33.4	60.9	62.64
Average price [€/MWh][28]	28,4	18,5	18,1

V CONCLUSION

This article has presented a combination of the merchant-FTR approach and the regulatory approach to transmission expansion in a competitive environment of price-taking generators and loads. We implemented a regulatory mechanism as an MPEC problem with a profit-maximizing Transco and a competitive wholesale market based on nodal pricing. Starting with a congested grid, the Transco is free to choose grid expansions that enhance its own profits (the congestion rent and a fixed fee). The Transco's profits are subject to a price cap with Laspeyres weights. The results show that the Transco expands the network and that prices converge toward marginal costs over the periods analyzed.

[27] Excluding auxiliary lines.
[28] Excluding auxiliary nodes.

We tested this approach using a simplified grid of northwestern Europe. This application to a real-world situation yielded outcomes similar to our simulated analyses: the nodal prices that were subject to a high level of congestion in the first phase converge toward a common price level representing the costs of marginal generation. Application of our incentive mechanism is thus compatible with merchant investment within organized electricity markets with FTRs Although we do not compare our approach with other expansion mechanisms used in practice (we do not equate current regulations and institutions with a “no-expansions-at-all” case), we have shown that our mechanism approximates a welfare optimum. To the best of our knowledge, we believe we are the first to do that. Additional research should of course demonstrate the robustness of the results obtained in this article. We suggest extending the model structure to consider myopic behavior as well as varying weights in price-cap constraints such as ideal weights that are quantities corresponding to the steady-state equilibrium and would grant convergence to it in just one period (as in Laffont and Tirole 1996). We further suggest employing variable pricing mechanisms (particularly zonal pricing) and examining the impacts of multiple Transcos that behave strategically within a single network. Another possible extension would be using sub-periods with different demand levels, although in this case we would not expect that results would vary significantly.

We believe that our mechanism helps to reconcile regulatory economics theory with electrical engineering. It explicitly upgrades the Vogelsang (2001) model to meshed networks by integrating the engineering constraints into its two-part price-cap regulatory logic. As illustrated by HRV and others, importing the main results of regulatory economics on network-congestion management into electricity grids is no trivial task. In accordance with recent major literature on the economics of regulating electricity, we abstracted from many relevant practically related issues that would be too extensive to include within a single study. That sets up an ambitious agenda for future research on incentives for electricity transmission expansion. Related topics include market power in the generation and FTR markets, potential substitution between generation expansion and transmission expansion, stochastic demand behaviors, cost uncertainties, and information asymmetries among the various agents of the transmission grid (such as between the regulator and the firm, between the firm and consumers, and among different transmission owners).

In practice, electricity transmission is a complex issue that involves far more than engineering and financial decisions. For instance, environmental issues often become critical as do political disputes among countries (in Europe) or states (in the United States) or even within states (as in northern and southern California). We believe nonetheless that our mechanism holds promise for practice in the real world. Its implementation could be carried out relatively easily and at low cost, providing potential increases in social welfare, congestion relief, and profits for firms. Electricity markets with different institutional settings would need only reliable information on nodal prices.

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Appendix A

To derive the power flow within the meshed network, we apply a DC-Load-Flow approach (Schweppe et al., 1988, and Stigler and Todem, 2005).[29] Assuming that real power flows are determined according to the differences in the voltage angles between two nodes, we model the real flow by focusing only on those voltage angle differences Θ_{ij}:

(13) $pf_{ij} = B_{ij} \cdot \Theta_{ij}$ power flow between node i and j

The line series susceptance B_{ij} of each line is obtained by focusing on the line reactances X_{ij}. The reactance X represents the opposition of a line to alternating current, based on the inductance or capacitance of the line or both. Together with the resistance R, they define the impedance of a line and thus determine the amount of power flowing over this line given the net injections. The line series susceptance B_{ij} is then derived via: $B_{ij} = \frac{X_{ij}}{X_{ij}^2 + R_{ij}^2}$. Generally, the resistance is assumed to be significantly smaller than the reactance ($X >> R$), and thus we do not consider it further in this analysis, simplifying the susceptance to: $B_{ij} = \frac{1}{X_{ij}}$

Power flows are directed, thus $pf_{ij} = -pf_{ji}$. The net injections q_i can then be derived by summing the incoming and outgoing power flows at one node:

(14) $q_i = \sum_j pf_{ij}$ net injection at node i

When the capacity k_{ij} of a line is increased, the reactance X_{ij} of that line will change as well, and therefore the overall power -flow pattern in the network is consequently affected. We must therefore include a connection between chosen capacity and resulting reactance. Adding capacity on a connection can be seen as adding further lines on this connection, which is similar to constructing a parallel circuit. In such a parallel circuit, the total impedance Z of the system is defined by $R_{total} = 1 \Big/ \sum_i \frac{1}{R_i}$

Assuming similar line characteristics Z and adding of N systems, this simplifies to $Z_{total} = Z/N$.

[29] The convexity of the DC load flow assumption provides desirable welfare properties for decentralized transmission expansion decisions as outlined in Bushnell and Stoft (1996 and, 1997). Real electric networks are not always linear and convex. Some of the implications of non-convexity in a transmission system using FTRs are discussed in Lesieutre and Hiskens (2005). They argue that for AC systems (like the Benelux transmission system), the feasible set of injections in a power-flow model might be non-convex when practical transmission capacity constraints are considered. This subsequently implies that the revenue adequacy theorem might fail to hold. In practice, most regional transmission organizations use a DC load -flow approximation to determine the feasible set of FTRs. But FTR markets in practice might fail to be revenue adequate at all times. Therefore, some markets (such as the New York ISO) have implemented policies to allocate financial coverage of shortfalls and benefits to transmission owners, and to allow them to reserve a small portion of transmission from FTR auctions in order to deal with shortfalls in congestion revenue. In terms of our model, non-convexity might imply that the solutions we obtain through the MPEC formulation are local optima, rather than unique solutions. As we show in another paper, however, piece-wise smoothness of the cost functions is what is needed for applying FTR price-cap incentive mechanisms to real-world transmission expansion (see Rosellón, Vogelsang, and Weigt, 2009).

If we assume that the lines have a starting capacity (k^0) and reactance (X^0), the functional connection can be expressed as:

(15) $$X_{ij}^{t} = \frac{k_{ij}^{0}}{k_{ij}^{t}} X_{ij}^{0}$$ line reactance and capacity

We assume starting values k^0 and X^0 given by the existing grid's topology.

To include the wholesale market in the profit maximization of the Transco, equations 13 to 15 are incorporated into the lower-level problem (equations 6 to 9).

Appendix B

Selected numerical results of the robustness test:

Table V: Base Case and Asymmetric Capacities

	Base case			Asymmetric transmission capacities (line2)		
	No grid extension	Regulatory approach	Welfare maximization	No grid extension	Regulatory approach	Welfare maximization
Consumer rent	108.00 €	145.44 €	149.01 €	118.00 €	146.21	149.01 €
Producer rent	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Congestion rent	24.00 €	4.45 €	0.99 €	24.00 €	3.71 €	0.99 €
Total welfare	132.00 €	149.89 €	150.00 €	142.00 €	149.92 €	150.00 €
Extension sum	-	5.53 €	5.90 €	-	3.61	3.90 €
Capacity: line 1	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW
Capacity: line 2	2.00 MW	6.56 MW	2.00 MW	4.00 MW	5.58 MW	4.00 MW
Capacity: line 3	2.00 MW	2.98 MW	7.90 MW	2.00 MW	4.03 MW	5.90 MW
Price: node 1	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 2	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 3	6.00 €	0.47 €	0.10 €	4.00 €	0.39 €	0.10 €

Table VI: Asymmetric Reactances and Asymmetric Costs of Line Extensions

	Asymmetric lien reactances (line2)			Asymmetric extension costs and reactances (line2)		
	No grid extension	Regulatory approach	Welfare maximization	No grid extension	Regulatory approach	Welfare maximization
Consumer rent	108.00 €	145.44 €	149.01 €	108.00 €	145.44 €	149.01 €
Producer rent	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Congestion rent	24.00 €	4.45 €	0.99 €	24.00 €	4.45 €	0.99 €
Total welfare	132.00 €	149.89 €	150.00 €	132.00 €	149.89 €	150.00 €
Extension sum	-	5.53 €	5.90 €	-	5.53 €	5.90 €
Capacity: line 1	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW
Capacity: line 2	2.00 MW	4.63 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW
Capacity: line 3	2.00 MW	4.89 MW	7.90 MW	2.00 MW	7.53 MW	7.90 MW
Price: node 1	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 2	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 3	6.00 €	0.47 €	0.10 €	6.00 €	0.47 €	0.10 €

Appendix C

Demand and generation data of the European test network:

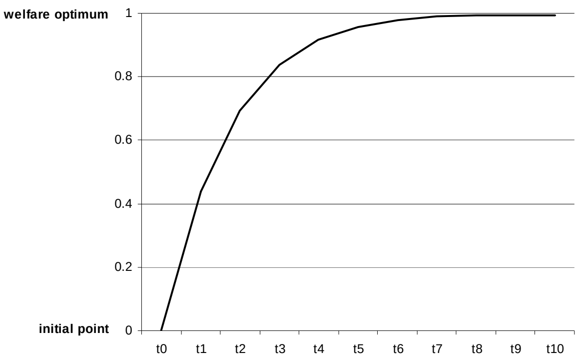
Table VII: Dataset of the European Test Network, in MW

Node	Nuclear	Lignite	Coal	CCGT	Gas/Oil	GT	Hydro	Pumped	Demand
Germany	20200	20400	28250	8700	10100	4400	4250	6300	63500
France	58100	580	15500	0	10200	0	12630	5200	55100
Gram	2120	0	2030	0	200	120	0	1310	2030
Krim	450	0	3370	3760	2530	350	0	0	8210
Maas	0	0	600	450	1610	0	40	0	1980
Merc	2620	0	1500	1570	3000	470	0	0	7960
Zwol	0	0	0	4130	530	0	0	0	2900

Appendix D

Figure 5: Welfare Convergence of the Regulatory Approach:

3 node base case



European test network